Central Maine Power

April 27, 2005

CONFIDENTIAL MATERIALS ENCLOSED

Cohen cc
McLaughlin
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Howe
Davidson
Sukadas

MAP Exhibit 5

Mr. Dennis Keschl
Administrative Director
Maine Public Utilities Commission
State House Station 18
242 State Street
Augusta, ME 04333

Re: MAINE PUBLIC UTILITIES COMMISSION,
Inquiry into the Status of the Reliability and Security of the Electric Grid
Docket No. 2004-248

Dear Mr. Keschl:

Enclosed please find the Response of Central Maine Power Company to the Commission Staff's Draft Report on the Reliability and Security of the Grid in Maine.

Please note that the Confidential Information provided in the enclosed Exhibit 5 is being provided under the terms and conditions of Protective Order No. 2, Confidential Business/Proprietary Information, issued in this proceeding on July 22, 2004.

Sincerely,

Maria E. Cooper

Maria E. Cooper
Analyst – Regulatory & Tariffs

/mec
Enclosures
cc: Service List, Docket No. 2004-248

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2004-248

April 27, 2005

MAINE PUBLIC UTILITIES COMMISSION
Inquiry into the Status of the Reliability and Security of the Electric Grid

COMMENTS OF CENTRAL MAINE POWER COMPANY

CENTRAL MAINE POWER COMPANY'S
RESPONSE TO THE COMMISSION'S DRAFT REPORT ON THE
RELIABILITY AND SECURITY OF THE GRID IN MAINE

A. INTRODUCTION

On April 29, 2004, the Maine Public Utilities Commission ("MPUC" or "Commission") initiated an inquiry for the purpose of conducting a study requested by the Joint Standing Committee on Utilities and Energy (the "Committee").[1] The Commission employed Liberty Consulting Group ("Liberty") to assist in the inquiry. On January 17, 2005, Liberty issued its report entitled "Report on the Adequacy of the T&D Systems of Maine's Four Electric Utilities" (the "Liberty Report"). A draft of the Commission's report was issued on March 28, 2005 (the

[1] During its 2003 session, the Legislature passed an Act to Encourage Energy Efficiency and Security (the "Act"). The Act directed the Commission to investigate regulatory mechanisms and rate designs that provide incentives for transmission and distribution utilities to promote energy efficiency and the security and robustness of the electric grid. As required by the Act, the Commission submitted a report to the Committee on February 1, 2004. In this Report the Commission stated that ensuring adequate service reliability through objective service quality metrics backed by meaningful penalties, incorporated as part of a performance based ratemaking plan, along with the Commission's ability to use its traditional tools to ensure adequate service, was working well. Accordingly, the Commission recommended that no legislative changes be made in this area at such time. The Commission stated that it would continue to monitor service quality performance and refine the standards and penalty mechanisms in ways that improve their operation. In a letter to the Commission dated February 23, 2004, the Committee requested that the Commission continue its inquiry and should specifically quantify the safety margin of the grid system, including through such indicators as maintenance activity, and to analyze how the margin may have changed over time, particularly as the result of alternative rate plans and restructuring; assess the adequacy of grid security in light of the events of September 11 and the blackout of 2003; examine issues of grid adequacy in remote areas, e.g., Washington County, including looping issues; and review relevant information including information from transmission and distribution utilities and reports on the blackout of 2003. The Committee requested that the Commission submit a report with its findings and recommendations during the next legislative session.

"Draft Report"). The Commission provided all stakeholders an opportunity to comment on the reports. Below are the comments of Central Maine Power Company ("CMP" or the "Company")[2] on both the Draft Report and the Liberty Report.

In summary, CMP agrees with the finding in the Draft Report that no legislative action is required at this time to address issues of safety and reliability. CMP concurs with the report's conclusion that all aspects of CMP's operation of its transmission system and substations appear to be of high quality. CMP also agrees with the conclusion that CMP meets the requirements of the ARP and, therefore, on a system level, CMP's distribution system is adequate. CMP's goal is to provide customers with the best possible electric delivery service while reducing its rates under performance based rate plans, and, in fact, CMP is accomplishing these two goals – ensuring 99.95% reliability[3] and decreasing rates by approximately 30% since 2000.

The Draft Report also expressed some concerns because of the perceived disparity between CMP's worst performing circuits and its overall SAIFI and CAIDI performance[4] and the nature and scope of CMP's reliability improvement program. The Draft Report concludes that an audit and a more detailed study of CMP's distribution system should be conducted as part of a further proceeding. CMP believes that an additional audit is not warranted based on the Liberty analysis, and particularly in light of CMP's clarification discussed herein of apparent misunderstandings by Liberty regarding CMP's practices. Moreover, CMP's current practices already provide an audit function. An additional separate physical audit is not needed and will do little to address the legitimate concerns raised in the draft report. Instead of such an audit,

[2] By way of call from Counsel to Staff on 4/26/05, the Commission gave CMP until April 27, 2005 to file its comments.
[3] Based on a percentage of total customer service hours compared to total outage hours.
[4] The Customer Average Interruption Duration Index ("CAIDI") is an average of customer interruption time per year; the System Average Interruption Frequency Index ("SAIFI") is an average of customer interruption frequency per year.

CMP recommends continuing to provide reliability data, including the enhanced distribution line inspection results and analysis, as part of its annual filings under ARP2000. For example, CMP could provide the findings each year under its distribution inspection program and describe what actions it took or will take to address areas of concern. The Commission can continue to use these annual proceedings to request data and monitor areas of concern.

As the Draft Report indicates, CMP has consistently met its reliability targets under both ARP95 and ARP2000. These targets were the result of protracted and intense negotiations, all part of a comprehensive regulatory plan under which CMP has operated, is operating, and will continue to operate.[5] The Commission approved the plans and recognized that they would operate to improve service quality and reliability (using CAIDI and SAIFI criteria to measure improvements) and reduce delivery rates.[6] In addition, ARP2000 provided for a mid-period review of service quality issues, during which any party, including the Commission, could raise issues of concern, including service reliability issues.[7] The parties to the mid-period review agreed by stipulation to revise the outage exclusion criteria and effected targets that made it more difficult for CMP to exclude outages from the reliability calculations. No other reliability issues were found to be inadequate.

The final report should recognize that these ARP service quality and distribution reliability criteria, and in particular the adopted CAIDI and SAIFI measurements, represent the

[5] ARP2000 adopted more stringent CAIDI and SAIFI measures and included new standards for customer services. ARP 2000 also increased the maximum penalty levels (to $3.6 million), despite the fact that CMP's revenues decreased by one-third.

[6] It is especially noteworthy that CMP has met its service quality and reliability criteria while at the same time reducing its rates through the high productivity offsets adopted in ARP2000. These offsets have decreased rates almost 10% since 2000 and over the course of ARP2000 will serve to decrease rates in constant dollar terms by 18%. Maintaining service quality and reliability criteria and delivering these rate decreases is a remarkable achievement of which CMP is proud.

[7] The mid-period review was designed to focus on the MPUC complaint ratio and the call center service quality (i.e., Customer Survey). In response to Staff's concerns about other issues, CMP agreed to work collaboratively with the

quantifiable reliability standards by which CMP's service should be evaluated. The distribution-related issues raised by the report are not "grid reliability issues" as that term is traditionally used regarding network security and reliability, but they are distribution service quality issues,[8] which both ARPs have addressed. CMP is concerned that the Draft Report, in essence, is now attempting to rewrite the reliability standards of the ARP through the grid reliability report.

As CMP describes below, several of the concerns mentioned in the report are based upon factual inaccuracies, result from a disagreement in interpretation of National Electric Safety Code ("NESC") requirements, or from differences of opinion in how to operate CMP's system.[9] In addition, as discussed below, despite similar vegetation management and distribution inspection programs at CMP and Bangor Hydro-Electric Company ("BHE"), the Draft Report reaches different conclusions, holding CMP to a higher standard.

A physical inspection of the entire distribution system as part of an audit would be time consuming, costly and would ultimately divert CMP's personnel from their primary responsibility of providing highly reliable service to CMP's customers and would be an expense outside the ARP. CMP has an inspection and maintenance program, as described in greater detail below, that will provide the information to address these concerns and ensure distribution reliability. As mentioned above, where the Commission has valid concerns about reliability,

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Staff and other parties to refine the CAIDI and SAIFI measurements and reduce the CAIDI and SAIFI outage exemptions from the agreed upon service area base to a company-wide base.

[8] In common usage, the term 'grid' refers to the backbone of a utility's delivery system, namely the transmission and substation portion of its system, not the distribution portion of its system. See, e.g., U.S. – Canada Power System Outage Task Force "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations" and FERC Order 2000; see, e.g., FERC Statement of Policy with regard to reliability dated April 14, 2004, 107 FERC ¶ 61,052, included as Exhibit 10. As the Draft Report clearly indicates, CMP has stellar performance in this regard.

[9] The National Electric Safety Code ® is National Standard C2-2002. "The purpose of the NESC rules is the practical safeguarding of persons during the installation, operation, or maintenance of electric supply and communication lines and associated equipment. The NESC contains the basic provisions that are considered necessary for the safety of employees and the public under the specified conditions. The NESC is not intended as a design specification or as an instruction manual," per the Institute of Electrical and Electronics Engineers, Inc.

CMP can provide information in its annual ARP2000 filings, and this will allow the Commission to monitor CMP's actions and provide any necessary information should the Commission seek to modify the service quality indicators in any future rate plans.

CMP provides in Exhibit 1 requested revisions to certain Draft Report statements, and in Exhibit 2 some clarifications to the Regulatory Paradigms: Bulk Power System section of the Draft Report.

B. **COMMENTS**

1. Standards and Practices for Transmission Reliability and Distribution Service Quality and Reliability are Appropriately Different

There appears to be a fundamental difference between the expectations of Liberty and CMP regarding maintenance of the distribution system because Liberty does not appear to value the service, quality and reliability criteria adopted by the Commission in ARP2000. Liberty, at page 5 of its report, states that it expected that CMP would maintain its distribution system in the same excellent manner as it maintains its transmission system and substations. Liberty criticizes CMP's distribution reliability without defining the applicable standard in a quantifiable fashion, as requested by the Committee in their charge to the Commission. As discussed in greater detail below, the interested parties and the Commission developed and adopted the current ARP2000 service quality and distribution reliability standards, especially the CAIDI and SAIFI metrics, as the appropriate quantification of distribution reliability under the ARP. This does not mean that CMP ignores particular customer service that falls below the company-wide CAIDI/SAIFI standards, however, it does recognize that the Company can meet reasonable reliability standards despite some variation.

As generally described in the Staff's Draft Report, CMP's transmission network is the backbone of its total electric delivery system. Reliability issues with the transmission system necessarily affect thousands and hundreds of thousands of CMP's customers at a time. It is imperative that CMP maintain its transmission system and substations to the highest standards, to achieve nearly 100% reliability.[10] Using the highway analogy, CMP's transmission system and substations are like the interstate highway and state highway systems, which are the backbone of Maine's transportation system. Much care and money are put into maintaining these highways to the highest standards so vehicles can pass uneventfully and quickly from one place to another. Similarly, the general level of care for a transmission system is higher than that for a distribution system because of the potential for broader system impacts. The Commission has never required a utility to maintain its distribution system to the same standards as it maintains its transmission system and substations. Rather, contrary to the Liberty approach, the Commission, consistent with every other state public utility regulatory agency, has established distribution service standards that recognize the inherent difference between transmission and distribution systems. The Liberty Report fails to recognize these differences and sets unreasonable expectations beyond current performance levels – performance levels that CMP continually meets and which have guided the Commission and other public utility commissions in establishing reasonable and effective distribution performance standards.

2. <u>ARP Performance Standards Adequately Address Less Densely Populated Areas</u>

The Draft Report expresses a concern that CMP's performance in the less densely populated areas of its service territory may have deteriorated, and in some areas, may no longer be adequate. Draft Order, p. 34. The Draft Report also raises concerns about CMP's reaction to these "poorly performing circuits", and suggests that CMP may be ignoring these areas as they

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[10] In fact, by agreement and requirement, CMP plans, operates, and maintains its transmission system in accordance with Northeast Power Coordinating Council, North American Electric Reliability Council, New England Power

do not deliver the same economic benefit under its ARP as in the more densely populated parts of its service territory. As discussed below, this is not the case. Moreover, this is not a new issue and has been raised during the annual ARP filings. CMP has consistently worked with the Commission Staff and other parties to collaboratively address and resolve service quality issues, including perceived poor rural service quality during the annual ARP filing through its identification and improvement of its worst performing circuits. CMP remains committed to this effort and can address the draft report's concerns in this context.

CMP agrees with the Draft Report conclusion that distribution reliability should not be maintained to improve the service of urban customers at the expense of rural customers, but CMP believes the Draft Report overstates the issues that may exist in the rural parts of CMP's service territory. CMP provides in its annual ARP2000 filing its ten worst performing circuits determined by how the circuit impacts CMP-wide SAIFI. CMP's reliability improvement program includes, as one component, remediation efforts for these circuits. Appendix C to the Draft Report contains a list of CMP's worst performing circuits from a SAIFI perspective,[11] measured by individual circuit. As can be clearly seen, the number of customers on most of these circuits is small. In fact, some of these circuits contain less than 100 customers. Given the rural nature of large parts of CMP's territory, it is reasonable to expect that some circuits feeding smaller numbers of customers will have higher SAIFI calculations.

CMP has a process to develop and implement remediation plans for each of the ten circuits to improve reliability. These ten circuits have a combined length of 1,601 circuit miles, i.e., approximately 7% of the entire distribution system of 22,585 circuit miles. Four of

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Pool, and ISO New England standards to ensure a reliable electric delivery system, and to avoid consequences such as those of the northeast blackout of August 14, 2003.

these circuits extend for more than 200 miles, and five more circuits are longer than 100 miles. This is significantly greater than the average length of a circuit in CMP's entire service territory, which is 54 miles. Eight of ten of the circuits on the 2004 "10 worst circuit listing" are 34.5 kV circuits that serve the most rural areas of CMP's service territory. Rural circuits are understandably exposed to more frequent tree and squirrel contacts and equipment damage caused by third parties than circuits in more densely populated areas. In addition, depending upon where a pole fault resulting from a car accident occurs along a circuit, an outage could affect the entire load served off that circuit. The longer the circuit, therefore, the more difficult line clearance is, and the more customers can be affected by an outage. Again, this is a problem experienced in rural areas, because urban circuits are on average much shorter.

The Draft Report also recognizes that service quality in every area of a utility's service territory will not, and need not, be identical. Draft Order, p. 34. Thus, higher outage numbers per circuit in longer circuits in rural areas should reasonably be expected. Despite the challenges due to the length of some of the circuits, and the proliferation of vegetation in rural areas, Table V on page 32 of the Draft Report demonstrates that the average SAIFI for the ten worst circuits, with SAIFI measured for each circuit, has decreased every year. This is evidence that CMP continues to focus considerable efforts to improve the performance of the circuits in the more rural parts of its system. The lack of complaints from customers is further evidence that CMP consistently delivers high quality service to its rural customers in heavily treed areas. For these reasons, it is unreasonable to conclude that CMP has any customers receiving service that generally would be considered below "minimum levels of adequate service." Draft Report at p. 34. The Draft Report and Liberty Report do not define or quantify what constitutes

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[11] Though the heading of Appendix C indicates that the appendix contains CAIDI information, the information in

"minimum levels of adequate service." CMP tries to provide continuous and stable electric delivery service to all of its customers, and while there are a variety of management and regulatory tools that currently exist to review and improve service, ultimately, its service quality and distribution reliability must meet the standards agreed upon and approved by the Commission and contained in ARP2000.

3. CMP's Vegetation Management Program is Proactive

a) Introduction

Relying in part on the comments on pages 6 and 11 of the Liberty Report, the Draft Report raises a concern that CMP's approach to vegetation management is "primarily reactive, and targets areas only after a service reliability problem exists". See Draft Report, p. 38. Liberty also states that CMP's "only objective is to meet the overall, short-term reliability levels required by the ARP." Liberty Report, p. 6. According to Liberty, CMP addresses only ten to 20 circuits that have already experienced problems, and that this approach should be revised to be more predictive, rather than reactive. See id. CMP disagrees with these assessments. Moreover, CMP notes that although Bangor Hydro-Electric Company's ("BHE") seven-year distribution vegetation management cycle is the same as CMP's program, BHE's program was found adequate in the Draft Report. See Draft Order, p. 55. These similar programs must be evaluated similarly.

Liberty correctly notes that CMP is required by the terms of ARP2000 to meet certain service quality and reliability targets. Failure to meet these targets results in the imposition of severe penalties. In fact, as stated above, CMP has met all of the ARP targets for SAIFI and CAIDI since 1995, even though targets have become more stringent. In operating

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the appendix is SAIFI data.

under the ARPs, however, CMP has never lost sight of its overall objective to provide safe and reliable service to its customers, and to ensure the highest degree of customer satisfaction.

The Draft Report's and Liberty's criticisms of CMP's vegetation management program suggest that they may not have a complete understanding of CMP's program, i.e., how CMP develops its annual work plan and conducts its tree trimming program. Specifically, the Draft Report's and Liberty's comments regarding CMP's procedures for tracking its vegetation management work and the numbers of spans worked on are simply not accurate, and require clarification. See id. The confusion about CMP's vegetation management program is highlighted by the finding that BHE's seven-year program, which is the same as CMP's, is adequate. See Draft Report, p. 55. CMP hopes that the following description will eliminate this confusion about the Company's vegetation management program.

b) Description of Vegetation Management

CMP manages an aggressive vegetation management program, which focuses on reliability and safety. This program employs a variety of management tools, beginning with the Company's planning process. CMP's vegetation management staff uses a matrix approach to plan the scheduled maintenance work for several years. As outage data has improved and with the implementation of the ARP, the SAIFI component is weighted more heavily, while other factors composing the matrix continue to be used to make the final selection of circuits to be worked on each year. The factors reviewed include overall SAIFI, tree SAIFI, total customers served on the circuit, number of tree-caused power outages, tree conditions (as observed by arborists in the field), power quality issues reported by CMP's customers, location of circuit from service center office, and years since last pruned.

The field inspection assists CMP in managing its 'danger tree' program. If the tree clearances are generally acceptable but tree-caused power outages are high, CMP assigns additional tree work, which includes tree removals and increased overhead clearances. CMP is proactive in the areas that have experienced actual tree outages, or that, in the professional opinion of the arborists, require additional tree work. This enhanced tree work is targeted to danger tree removal and increased overhead clearances.

CMP also manages a 'hot spot' program. Hot spot detection provides a degree of flexibility to address immediate threats to individual locations along the overhead wires. Such a flexible 'time and materials' approach allows the arborists the discretion to select and prune areas that require immediate attention. CMP also prunes a significant number of spans as part of system improvement projects, Maine Department of Transportation (“MDOT”) road jobs, and new construction projects.

When analyzing CMP’s program, one must account for all of the spans worked. The scheduled maintenance program, hot spot program, danger tree program, and construction projects must be totaled to provide a clear picture of how much of the distribution system is maintained each year. During 2004, for example, CMP completed tree work on 2,520 brush miles, which is about 14% of the system that is covered by tree growth. On the basis of doing tree work on approximately 14% of the system each year, CMP's entire distribution system will be cleared every seven years. This aggressive vegetation management program is critical to long-term reliability and reduced costs. Moreover, CMP is very aggressive in its approach to tree removals. Last year, for example, CMP removed about 25% of the trees that were worked on by contract crews. This means that for every tree that CMP touched to do some sort of vegetation management, CMP removed 25% of such trees entirely as opposed to just doing trim.

CMP treated 190 miles of roadside right-of-way ("ROW") with a foliar herbicide application[12], which will extend the length of time that a crew will be required to return for maintenance. The aggressive cut surface treatment program also extends the time before trees will overgrow the wires, which further reduces long-term cost, because the herbicide prevents the tree from re-sprouting.

In July 1988, CMP's consultant conducted a study to determine the average growth rates of the tree species most commonly found adjacent to the power lines. The average growth rate of the fastest growing trees was used to help calculate the clearance specification. CMP's vegetation management program provides a minimum of five years of clearances before limbs would overgrow the conductors[13]. Although CMP has considered larger clearances for fast growing species (cycle busters), the Company is limited in its ability to prune and remove trees in the public way. See 35-A M.R.S.A. §2522. CMP tries to balance its need to keep its distribution lines clear from tree limbs to maintain system reliability, with the public's desire to preserve Maine as a forested state. Accordingly, CMP has maintained constant clearing specifications since 1989. Given Maine's snow load and icing issues, CMP has not recommended reducing its clearances, in an effort to cover more miles each year.

Finally, CMP has extended its maintenance budget by entering into cost share maintenance clearing programs with telephone companies, and to a lesser degree, with cable companies and municipalities. In addition, CMP recently entered into a sole contract for vegetation management with a vendor that has resulted in more line clearance being

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[12] CMP returns to these managed areas one year after and sprays foliar herbicides to prevent resprouting. This technique provides CMP 10 years before having to do extensive trim work in these areas.

[13] CMP's reliability based vegetation management program, including trim work on the ten worst circuits, additional trim on other circuits, surface treatments, foliar herbicide treatments, removal of danger trees and the hot spot program, is adequate to address the five-year average growth time determined by CMP's consultant.

accomplished at a lower cost per span.[14] The estimated savings from the contract are $1.1 million per year, which has enabled CMP to accomplish more vegetation management work while maintaining a fairly constant annual vegetation management budget.

c) Information Provided to Staff

Contrary to the concern in the Draft Report with CMP's tracking procedures, since 1991, the Company has consistently tracked its vegetation management activities by town, road and pole for every circuit. Draft Report, p. 38. In the course of this proceeding, CMP provided Staff and Liberty with ten years of data listing the number of spans worked on for each year, and a list of all of the circuits on which trimming work was performed in 2003 and 2004. The total number of circuits worked on in 2003 was 87, three of which were carried into 2004. In 2004, 71 circuits were included in the routine maintenance plan. Other information provided in this proceeding included the number of spans cleared in 2003 (60,591). In response to ODR-01-09, attached hereto as Exhibit 3, as well as ODR-01-12, attached as Exhibit 4, CMP provided this information to Staff and Liberty, as well as an explanation of the criteria the Company uses to develop its annual work plan and to determine which spans of which circuits will be targeted that year. As required under the terms of ARP2000, CMP reports annually to the Commission on its vegetation activities for the ten worst circuits, and specifically identifies the actions taken to improve reliability on each circuit. In fact, CMP goes beyond the requirements of ARP2000. As part of the Company's internal ranking system, CMP reviews the 20 worst circuits, and evaluates the need for preventative work, including maintenance trimming, hot spot work or danger tree work.

[14] These are the types of real savings that allow CMP to deliver the high productivity offsets promised by ARP2000.

The Company maintains the data regarding its vegetation management program on its computer systems back to 1998, and the data back to 1991 is available in its archived files. To show the Commission the type of data that CMP has available, Exhibit 5 **(confidential under Protective Order No. 2, Confidential Business Information, issued in this proceeding on July 22, 2004)** to these comments is a map of circuit 873D1 which appears on CMP's list of the ten worst performing circuits. This circuit is in a very rural area (Belgrade, Rome, Sidney, Mount Vernon). The map shows the outages and outage types for 2004 and vegetation management done since 2000. The Draft Report should be corrected to reflect that CMP does keep very detailed records of its vegetation management program.

The Liberty Report at page 6 states that CMP should inspect 100% of the vegetation management work done by its contractor. CMP disagrees. CMP formally audited and documented the results of 22% of the maintenance work in 2004 and 19% of all spans worked on in 2004. The percent of rework found to be necessary in the audit process was 0.009% of all spans completed. The rework percentage is a performance measure to assess contractor performance and penalties are imposed for failure to meet the criteria under the contract. CMP's arborists increase the number of audits if problems are noted on the scheduled audits. It is better for CMP to spend time on actual vegetation management work than on additional auditing of contractor work. CMP's current activities in this area are adequate.

4. CMP has a Thorough Inspection and Maintenance Program

During the course of the inquiry, the Commission Staff expressed a concern with CMP's distribution line inspection program. As discussed in more detail below, CMP met with the Staff to discuss these concerns and volunteered to make revisions to its distribution inspection program. Following these revisions, CMP believed the Company had satisfied the

Staff's major concerns. However, the Draft Report suggests continuing dissatisfaction with CMP's distribution line inspection procedures. <u>See</u> Draft Report, pp. 38 – 40.

a.) <u>CMP Has Formal Inspection Procedures</u>

The Draft Report raises a concern about the "informality" of CMP's procedures. In fact, as described below, CMP has had formal inspection procedures in place since 1999, and has improved upon these procedures in response to meetings in this proceeding with Commission Staff and Liberty, as recently as December 2004.[15]

b.) <u>CMP's Inspection Program Complies with the NESC Requirements</u>

On page 39 of the Draft Report, there also appears to be some question as to whether CMP is in compliance with NESC's requirements for distribution lines. As a point of clarification, therefore, CMP's distribution lines are in compliance with NESC requirements. Specifically, Section 21.214(A)(2) provides:

> Lines and equipment shall be inspected at such intervals <u>as experience has shown to be necessary.</u>
>
> Note: It is recognized that inspections may be performed in a separate operation or while performing other duties, as desired.

(Exhibit 6, emphasis added). Consistent with this requirement, CMP employs a variety of inspection programs and techniques, including the following: (i) CMP annually inspects via infrared technology 100% of its 3-phase distribution system, which is equivalent to 18% of the circuit miles of the distribution system; (ii) CMP annually inspects approximately 7.5 % of its

[15] See Section 4(c) infra, Response of EX-01-13 and Supplemental EX-01-13.

circuit miles related to its ten worst performing circuits[16], while implementing mitigation plans for its under-performing circuits from the previous year; (iii) CMP's vegetation management team also annually inspects approximately 10% of its circuit miles and reports issues spotted; (iv) in the course of responding to outage calls, CMP inspects a portion of its circuit miles each year; (v) CMP annually checks loads and counters on every distribution recloser on nearly all of its distribution circuits and takes measurements of the electrical loads at the substation on nearly all of its distribution circuits each year; and (vi) in accordance with CMP's inspection policy (Field Operating Procedure 409), all field employees (e.g., lineworkers, line inspectors, substation technicians, etc.) routinely inspect CMP's distribution equipment during the performance of their jobs, including visual roadside inspections.

c) CMP Maintains an Adequate and Effective Inspection Program

The concern raised in the Draft Report that "it is possible that a circuit that was inspected near the beginning of the last inspection cycle will go without inspection for 20 years" is not correct, and once again may stem from some confusion about CMP's inspection procedures. See Draft Report, p. 40. The Draft Report's statement that "CMP suspended its prior formal inspection program in 1999" is incorrect. See id. Although CMP modified its line inspection procedures in 1999, it never suspended its inspection activities. Thus, there likely will be no such gap in the inspection cycle as the Draft Report suggests.

Response EX-01-13, and Supplemental Response EX-01-13 (Exhibit 7 and Exhibit 8) describe CMP's distribution line inspection procedures, including the revised Field Operating Procedure 409, both before and after CMP implemented modifications and improvements in December 2004 following discussions with the Commission Staff. In

[16] The Draft Report states that the ten worst circuits represent 2.5 % of CMP's distribution system. In fact, as

summary, prior to the recent revisions, CMP performed distribution system inspections through infrared inspection, field reporting of failed equipment, recloser inspection program and distribution line inspections, each performed at various times throughout the year. This type of program is more extensive than the program BHE used during the same approximate time frame. Coincidentally, CMP has had better CAIDI and SAIFI measurements. The revisions to the procedures, effective in January 2005 include, a ten year inspection cycle based upon ten (10%) percent of distribution circuits in each service center region, centralized record keeping and prioritization of corrective maintenance work and preventative maintenance procedures.[17] CMP will collect and review the inspection data to develop correction and preventative measures, as well as to modify its inspection program.[18] The inspection results and analysis will be part of the annual ARP filing and this information, including trend analysis, will be particularly useful to understanding the actual condition of CMP's distribution system and monitor CMP's actions.

5. CMP Employs a Proactive System Improvement Program

The statement in the Draft Report that "when a circuit reaches 80% to 90% of its rated capacity, the circuit is considered for improvement" is not accurate. In fact, when a circuit reaches between 80% and 90% of capacity, these circuits are monitored to evaluate if cold load pickup after an event, or tying the circuit to another may have caused the higher reading. The circuit is also monitored to verify that the overload is not an isolated occurrence due to an unusually warm day. As most overloads on distribution lines occur during the summer when ambient temperatures are at their highest and the current carrying capacity is reduced, it is

previously stated, the ten worst circuits represent 1,601 circuit miles, or 7% of CMP's entire distribution system.

[17] This revised program is similar to the periodic inspection program also recently adopted by BHE.

[18] CMP also agrees with the comments of BHE regarding periodic testing of distribution and roadside transmission pole plant (see BHE's response dated April 11, 2005, at pages 9 – 10), and wishes to emphasize, as discussed with the Commission Staff regarding revisions to CMP's distribution line inspection program, CMP will evaluate

necessary to wait until the following year to see if there is a recurrence of overload on that circuit. CMP provides as Exhibit 9 a corrected version of a list of circuits operating at 90% or greater ampacity and what actions CMP took or will take regarding these circuits. In this update, CMP states what action is being taken to address capacity issues on these circuits. This list is all-inclusive for 2004.

Also, on page 6 of its report, Liberty states that CMP is allowing at least two of its circuits to operate at about one and one-half times the circuit ratings, and concludes that this is not good utility practice. Instead, Liberty advises CMP to construct feeder reinforcements to prevent such overloading. See id. CMP respectfully disagrees with Liberty because constructing a feeder in anticipation of possible overloads is not a cost-effective use of money. CMP analyzes its monthly and annual test data along with any potential new or added customer loads to determine where the system needs to be reinforced. Circuit feeders become overloaded for a variety of reasons. Storm outages for example, may result in cold load pickup which is a temporary situation. If a tie between two circuits is used, this could also temporarily overload a feeder. Both situations occur in the normal course of operations, and do not require construction of a feeder. As discussed earlier, contrary to generally accepted utility practices, Liberty seeks to treat distribution circuits as it would transmission lines. Distribution systems are not designed to meet every remote contingency, and Liberty's suggestion that they should is unreasonable and outside sound utility practice.

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whether, and to what extent, additional pole inspection and maintenance are required as part of its review of the inspection data and during the annual ARP filings.

6. CMP Maintains Ample Record Keeping to Assist in Identifying Potential Reliability Problems Before They Occur

Liberty concluded that CMP's record keeping was one of the "warning signs of precursors to reliability problems". Liberty Report, p. 5. The Draft Report also expressed a concern about CMP's record keeping. See Draft Report, p. 42. The record demonstrates, however, that CMP maintains monthly substation demand readings on every distribution circuit and annual amp checks on all of its distribution reclosers. This data is used to identify which feeders may require additional study. The circuits shown on Exhibit 9 result from this process. As one-time overloads are a common occurrence in any distribution system, CMP does not study or track circuits that experience an isolated overload occurrence.

C. **CONCLUSION**

The Commission should, after considering CMP's comments, revise its Draft Report to reflect the factual corrections and additional information provided. In particular, the final report should reflect the following conclusions: (1) CMP is meeting the distribution service quality and reliability criteria agreed to in ARP2000, and these are the relevant distribution standards; (2) CMP has implemented enhanced cycle based distribution line inspection procedures in response to the Staff's concerns that meet the letter and intent of the NESC; and (3) CMP will continue to address distribution reliability concerns with the Staff (and other parties) during its annual ARP filing. Therefore, based on these conclusions, the final report should not require CMP to conduct an audit as part of further proceedings.

Respectfully submitted,

R. Scott Mahoney / UEC

R. Scott Mahoney
Vice President – Controller,
Treasurer and Clerk
Central Maine Power Company

CMP REQUESTED REVISIONS TO STAFF'S DRAFT REPORT

Page Ref.	Draft Report	CMP Requested Revisions
Page 38	The Commission is concerned, however, with the design of CMP's program, in that it appears to be primarily reactive, and targets areas only after a service reliability problem exists. An additional area of concern is that, during the investigation, CMP could not identify, and apparently does not track, which particular areas were worked on and thus could not state how long it had been since a particular span of circuit had been trimmed.	The Commission is concerned, however, with CMP's emphasis under its program on areas only after a service reliability problem exists. CMP tracks which particular areas were worked on and can tell how long it had been since a particular span of circuit had been trimmed.
Page 39	However, the Commission is concerned about the length of time that it might take CMP to inspect all of its circuits given the 10-year inspection cycle and the substantial time period during which CMP had no formal inspection process. CMP suspended its prior formal inspection program in 1999. Since CMP was on a five-year cycle at that time, it is possible that a circuit that was inspected near the beginning of the last inspection cycle will go without inspection for 20 years. This gap is unacceptable from both a safety and reliability standpoint and is addressed further in our conclusions and recommendations section.	We require that CMP provide the results of its inspections and actions taken on the findings of the inspections in its annual ARP2000 compliance filing. The Commission plans to monitor CMP's distribution inspection program to determine whether the concerns we express in this report are alleviated.
Page 41	However, the aging of CMP's plant is of some concern to us when combined with its suspension of its inspection program and fairly flat level of spending on its distribution maintenance program,	However, the aging of CMP's plant is of some concern to us when combined with the fairly flat level of spending on its distribution maintenance program,.

Pages 41 and 42	During the interview process, CMP stated that when a circuit reaches 80% to 90% of its rated capacity, the circuit is considered for improvement. CMP was asked to provide a list of circuits currently above 90% of capacity, and a list of those above 100% capacity, and for those circuits above 100% capacity the time period that they have been above 100% capacity. In its response, CMP provided a list of "2005 System Improvement Projects with Circuits Operating at 90% or Greater of Rated Ampacity". See Appendix F. CMP has stated that it could not, beyond the list of betterment projects, identify what circuits were above 90% or 100% and how long such circuits were above such ratings.	What do we want the report to say here?
Page 42	CMPs distribution planning record-keeping, or lack of record-keeping, is of concern to us. Specifically, it appears that CMP cannot tell the capacity or margin of safety on its circuits, or verify that it is following its planning criteria and good utility practice. The lack of such record-keeping also impairs the Commission's ability to verify that CMP's circuits have adequate capacity and that CMP is taking appropriate actions to address any inadequacies.	Delete this paragraph.
Page 43	The circuits identified annually by CMP for improvement therefore represent approximately less than 2.5% of CMP's distribution system in terms of circuits.	The circuits identified annually by CMP for improvement represent approximately 7% of CMP's distribution system in terms of circuit miles.
Page 44	This concern is heightened by CMP's previous suspension of its distribution inspection program, the aging of CMP's plant, the increase in outages and what appeared to be inadequate record-keeping in CMP's distribution planning and	This concern is heightened by CMP's prior informal distribution inspection program, the aging of CMP's plant and the increase in outages. While we cannot conclude based on the information collected during this study

	maintenance operations. While we cannot conclude based on the information collected during this study that CMP's service or plant in any particular aspect is in fact inadequate, we believe that enough "red flags" have arisen during this examination to warrant further review. As noted previously, CMP has on its own accord reinstituted a distribution line inspection program. While CMP's new program should bring CMP back in compliance with the NESC, under its new program CMP will only be inspecting 10% of its circuits annually, and therefore it may take considerable time before CMP reviews its entire system. We conclude that a more detailed study of CMP's system, similar to the study that was commissioned by Maine Public Service Company and which is discussed in section IV(D)(2)(g), should be conducted in the coming months to review the physical state of its distribution plant as well as its distribution planning and maintenance procedures. We will initiate an inquiry to determine how such an audit should be conducted.	that CMP's service or plant in any particular aspect is in fact inadequate, we believe that we need to gather additional information so that we can monitor CMP's progress in addressing the issues we raise in this report. As noted previously, CMP has on its own accord reinstituted a distribution line inspection program. We require CMP to provide in its annual ARP2000 compliance filing the results of its idistribution inspection program and action taken to address the findings.

III.A Bulk Power System

Page 7 Correct description from: "bulk electric power system that serves most of North America comprises three grid networks…" to: "the interconnected systems are roughly; west of the Rockies, Texas, east of the Rockies and Quebec. Quebec is similar to Texas (and the other networks) in that its only interconnections outside its network are asynchronous, or DC, connections."

III.A.3 NPCC

Page 10 Modify the statement that: "NPCC reviews all bulk power system modifications proposed by regional entities… ." to reflect that: NPCC does review significant modifications proposed by regional entities, from a system protection perspective only. NPCC assesses individual 'Area Reviews' of system performance in detail at least once every five years. That review is done for each Area as a whole, and is not a review of individual modifications.

III.A.4 ISO-NE and Maritimes

Page 11 Modify the statement that "ISO-NE… acts as the system reliability coordinator for the New England states and the Canadian Provinces of New Brunswick, Nova Scotia and Prince Edward Island… ." to reflect that: ISO-NE is the system reliability coordinator for New England, but has only an information/communications reliability coordination role for Maritimes Canada.

Page 12 Since RTO New England came into being in February, the satellite control centers have been known as 'Local Control Centers.' Also on page 12, Staff claims that NERC certification is not mandatory for operators of the satellites. In fact, the Maine Local Control Center will require NERC certification for its operators.

Footnote 9 The Vermont Local Control Center is undergoing testing and will be fully operational in July 2005. A Boston Local Control Center is planned to enter service in 2006.

III.B Restructuring in Maine

Page 14 Modify the statement that "FERC has not, as of this date, clearly asserted jurisdiction over local transmission systems and the jurisdiction over reliability matters for this portion of the grid remains somewhat unclear… ." to reflect that: FERC has asserted jurisdiction over transmission in Order 888, and has left it to the states to assess what facilities constitute transmission versus distribution under the FERC 'seven factor test.' As to at least CMP and BHE, the MPUC has agreed to transmission tariff settlements that reflect such a split of jurisdiction and FERC has concurred.

V.A.1 Bulk Power System Operational Overview Status

Page 79 Modify statement that: "In contrast to the rest of the New England bulk power system, Maine's demand for electric power peaks during the winter season, when the regional grid is typically less stressed than during the summer season… ." to reflect that Maine's demand for electric power has peaked during both the summer and winter seasons since the mid-1990s, depending on which season has more sustained extreme weather.

CENTRAL MAINE POWER COMPANY
RESPONSE TO FIRST SET OF ORAL DATA REQUESTS
DOCKET NO. 2004-248

October 7, 2004

ODR-01-09

Q. a) Provide documentation used to develop priority list of or vegetation management; and

b) Provide matrix of circuits that will have maintenance conducted including prior years, if available.

A.

a) CMP uses a variety of criteria to plan the distribution maintenance work. The primary parameter considered is SAIFI. The tree SAIFI for each circuit is evaluated. The other major areas of consideration include the prior year's SAIFI, the number of tree caused power outages, visual inspection of tree and brush conditions by a qualified CMP arborist, a review by power quality issues, distance of circuits from service center and coordination with CMP betterments or MDOT projects. Based on the above criteria and resource allocation the annual work plan is developed. Please also see CMP's responses to *EX-01-09* and *EX-01-10*.

b) Please see the two attachments for the distribution circuits on which CMP has done or plans to do vegetation management during 2003 and 2004.

Response Prepared and Submitted By:
Weston J. Davis
Manager, Vegetation Management

Attachments:

1. 2003 Projected Maintenance Circuits
2. 2004 Planned Work

2003 PROJECTED MAINTENANCE CIRCUITS										
Alfred	**Augusta**	**Bridgton**	**Brunswick**	**Dover**	**Fairfield**	**Farmington**	**Lewiston**	**Portland**	**Rockland**	**Skowhegan**
100D1	207D2	406D1	204D1	820D1	807D1	403D1	412D1	610D1	214D1	822D1
633D1	208D2	406D2	204D3	821D3	860D1	428K4	412D2	610D2	214D3	866D1
640D1	240D1	406D3	204D6	834D1	873D1	447D1	424D2	624D1	214D4	
640D2	242D1	435D2	206D1	834D2		816D1	424D4	635D1	239D7	
640D3	242D2	435D3	219D1			835D1	424D5	635D2	239D8	
657D4	256D1	430D1	223D1			844D1	424D6	644D1	239D9	
661D2	263D1		249D2			858D1B	426D2	660D1	246D1	
671D1			250D1			858D3	426D3	674D1	803D6	
671D2			252D2			882D2	426D8	674D2	805D1	
676D1			258D1				436D7	678D1	806D1	
678D1			273D4				450D2			
681D1			273D5							
681D2										

2004 PLANNED WORK											
	Alfred	Augusta	Bridgton	Brunswick	Dover	Fairfield	Farmington	Lewiston	Portland	Rockland	Skowhegan
Carry over		236D1			834D2						854D1
Circuits	419D1	211D1	413D1	225D3	815D2	807D1	428D3	420D6	218D1	214D1	822D1
	602D1	215D2	415D1	232D1	821D1	860D1	447D3	431D1	624D1	239D7	866D1
	603D1	215D3	419D1	241D1	821D2	870D1	453D1	431D2	639D1	245D2	868D1
	610D1	215D5	438D1	245D1	834D1	873D1	841D1	436D1	644D2	270D1	
	612D2	220D1		257D1			875D1	436D2	644D3	800D1	
	621D1	236D1		258D1				436D3	690D3	806D2	
	621D2	256D3		273D4				454D2		846D1	
	634D3	272D4		273D5				456D2		860D2	
	638D1										
	656D1										
	661D1										
	667D1										
	667D2										

CENTRAL MAINE POWER COMPANY
RESPONSE TO FIRST SET OF ORAL DATA REQUESTS
DOCKET NO. 2004-248

October 7, 2004

ODR-01-12

Q. Please provide the dates for changes in vegetation management policy procedures, and briefly describe the previous program(s) and the program that is currently in place.

A.

1989 to 1995: CMP implemented many of the recommendations suggested by Environment Consultants, a consultant employed by CMP. CMP considered a five-year distribution vegetation management cycle but never implemented a full five-year cycle program.

1995 - 1999: CMP used a matrix approach based on outage history and brush conditions to select maintenance areas. CMP also experimented with trimming entire circuits in one to two consecutive calendar years.

1999 - 2000: This was a transition period as CMP was preparing for new ARP targets, however, SAIFI/CAIDI continued to be used as major factors in combination with other data to create the annual work plan.

2001 - 2004: CMP used SAIFI as a primary factor to select distribution tree work, although other data continued to be evaluated *in the planning matrix.* Data which is reviewed included prior year's SAIFI, tree caused power outages, visual inspection of tree and brush conditions, review of power quality issues, location of circuit from service centers and coordination with CMP betterments or MDOT projects.

Please also see CMP's responses to EX-01-09 and EX-01-10.

Response Prepared and Submitted By:
Weston J. Davis
Manager, Vegetation Management

Exhibit 6

Section 21.
General Requirements

210. Referenced Sections

The Introduction (Section 1), Definitions (Section 2), References (Section 3), and Grounding Methods (Section 9) shall apply to the requirements of Part 2.

211. Number 211 not used in this edition.

212. Induced Voltages

Rules covering supply-line influence and communication-line susceptiveness have not been detailed in this code. Cooperative procedures are recommended in the control of voltages induced from proximate facilities. Therefore, reasonable advance notice should be given to owners or operators of other proximate facilities that may be adversely affected by new construction or changes in existing facilities.

213. Accessibility

All parts that must be examined or adjusted during operation shall be arranged so as to be accessible to authorized persons by the provision of adequate climbing spaces, working spaces, working facilities, and clearances between conductors.

214. Inspection and Tests of Lines and Equipment

A. When In Service

1. Initial Compliance With Rules

   Lines and equipment shall comply with these safety rules when placed in service.

2. Inspection

   Lines and equipment shall be inspected at such intervals as experience has shown to be necessary.

   NOTE: It is recognized that inspections may be performed in a separate operation or while performing other duties, as desired.

3. Tests

   When considered necessary, lines and equipment shall be subjected to practical tests to determine required maintenance.

4. Record of Defects

   Any defects affecting compliance with this code revealed by inspection or tests, if not promptly corrected, shall be recorded; such records shall be maintained until the defects are corrected.

5. Remedying Defects

   Lines and equipment with recorded defects that could reasonably be expected to endanger life or property shall be promptly repaired, disconnected, or isolated.

B. When Out of Service

1. Lines Infrequently Used

   Lines and equipment infrequently used shall be inspected or tested as necessary before being placed into service.

2. Lines Temporarily Out of Service

   Lines and equipment temporarily out of service shall be maintained in a safe condition.

3. Lines Permanently Abandoned

   Lines and equipment permanently abandoned shall be removed or maintained in a safe condition.

CENTRAL MAINE POWER COMPANY
RESPONSE TO EXAMINER'S FIRST SET OF DATA REQUESTS
DOCKET No. 2004-248

July 30, 2004

EX-01-13

Q. Please describe and provide documentation for the Company's criteria and procedures for establishing priorities and determining when and where O&M on the T&D system will be done.

A. The following criteria and procedures for establishing priorities for operation and maintenance efforts are in place at CMP:

(1) Transmission:
Central Maine Power Company's Transmission Maintenance Inspection Program is designed to be fully compliant with NEPOOL OP3 Appendix 3C1; "Transmission Maintenance Scheduling for Facilities Operating at 115 kV and Above". Please see Attachment 3 to the response to EX-01-26 for OP3.

The vegetation on transmission rights of ways system is managed on a four (4) year cycle. Work includes screen pruning and integrated vegetation management program. The danger tree and side trimming work is based on outage history, tree growth, right-of-way width, and professional arborist's observations. For a description of CMP's vegetation management plan, please see the response to EX-01-10.

The various inspection and remedial treatment programs are designed to identify where components of the transmission system have failed or are deteriorated and in need of scheduled replacement. The inspection program is fully described in the response to EX-01-27.

Central Maine Power utilizes a four-step priority system to determine when and where the repairs will be performed:

Priority	Description	Scheduled Repair
1	Failed components resulting in an outage	Repair immediately.
2	Damaged or failed components that may cause an outage.	Repair within the current year.
3	Deteriorated components with sufficient remaining life to be scheduled as planned maintenance.	Repair within the next two years.
4	Minor levels of deterioration that do not impact the integrity of the transmission system.	Continue to monitor and repair as other work is scheduled within the immediate area.

CENTRAL MAINE POWER COMPANY
RESPONSE TO EXAMINER'S FIRST SET OF DATA REQUESTS
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EX-01-13 Page 2

(2) Distribution:
CMP prioritizes its O&M work on the T&D system in order to achieve service quality targets established in ARP 2000 as well as to improve the performance of its underperforming circuits; some of this work is capital. In addition, CMP responds to customer requests for service and customer issues, particularly as they relate to CMP's Customer Service Guarantee Program and customer service inquiries.

The distribution vegetation management program is operated on a reliability-based system. Each year the circuits are reviewed and those with the highest outages and power quality issues, and using professional arborist's observations of the potential to create tree related problems, are selected for routine maintenance work.

CMP also has the following inspection programs in place:

Distribution Infrared Inspection (Fidd Operating Procedure ("FOP") Section 408):
Work is prioritized as follows:
Greater than 135 degrees indicates emergency
Greater than 90 degrees indicates repair as soon as possible
Greater than 50 degrees repairs should be done soon
Greater than 20 degrees do repairs with next scheduled outage
Less than 20 degrees informational only.

Distribution Line Inspection (FOP Section 409):
Whenever inspecting, working on or traveling over the CMP Co. System, Company personnel shall observe and report problems.
Any hazardous condition, that in the judgement of the field employee requires immediate action, shall be called in to the appropriate Service Center. Following verbal reporting, an SX order should be created on the Work Management System (WMS) detailing and documenting the reporting of the hazard.

Field Reporting of Failed Tools, Hardware and Equipment (FOP Section 504):
The purpose of this procedure is to determine and document failure rates experienced with the Company's various standard tools, hardware and equipment. The documentation of these failures will provide a means for the Company to evaluate the history of the failure and take appropriate steps to correct the problem.
All hardware and equipment failures on the Central Maine Power Company's distribution system shall be reported to the Distribution Standards Engineer via the on line Form 899, Field Report of Failed Hardware and Equipment.

Recloser Inspection Program (FOP Section 510):
The objective of this program is to establish a comprehensive recloser maintenance and inspection plan, which will ensure the availability of properly working protective devices.

CENTRAL MAINE POWER COMPANY
RESPONSE TO EXAMINER'S FIRST SET OF DATA REQUESTS
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EX-01-13 Page 3

Change-out requests are recorded on a Distribution Recloser Request Form. The need for change-out will be determined by the type and number of operations. Reclosers that have been damaged, especially leaking oil, shall be scheduled for replacement as soon as possible.

CMP also relies on the training and experience of its operations employees (managers, supervisors, lineworkers, meter technicians, and others) to observe, report and repair T&D facilities. Some of this training is described in attached training packages. Inspections are performed during the normal course of business, including during routine service work and emergency service restoration, or as scheduled on an ad hoc basis, based on the factors described above in the first paragraph of this section. The objective of these inspections is to identify and report all infractions of the NESC and all hazardous and potential hazardous conditions (see, e.g., CMP's Safety Manual) consistent with good utility practice as outlined in Field Operating Procedure 409.

CMP has the following training packages and safety manual:

Safety Manual
Storm Duty Training Package for Assessors
Storm Duty Training Package for Patrollers
Storm Duty Training Package for Runners

See also EX-01-03.

Response Prepared and Submitted By:
Stanley C. Grover
Manager Transmission & Distribution Support

Weston J. Davis
Manager, Vegetation Management

Constance J. Hayward
Director, Transmission & Distribution Support

Attachments:
1. Field Operating Procedure Section 409
2. Safety Manual
3. Storm Duty Training Package for Assessors
4. Storm Duty Training Package for Patrollers
5. Storm Duty Training Package for Runners

CENTRAL MAINE POWER COMPANY
RESPONSE TO EXAMINER'S FIRST SET OF DATA REQUESTS
DOCKET No. 2004-248

December 27, 2004

EX-01-13 Supplemental Response

Q. Please describe and provide documentation for the Company's criteria and procedures for establishing priorities and determining when and where O&M on the T&D system will be done.

A. In addition to the criteria and procedures described in EX-01-13 dated July 30, 2004, CMP will revise its distribution line inspection procedures based on its further review and participation in Docket No. 2004-248. The revisions to CMP's Distribution Line Inspection Procedures, effective January 2005, will include the following: ten (10) year inspection cycle based on ten percent (10%) of distribution circuits in each service center region; NESC compliance; standard inspection standards, training and reports; centralize record keeping; and prioritize corrective maintenance and preventative maintenance consistent with current procedures. CMP will implement these revisions into existing criteria and procedures in order to achieve service quality targets established in ARP-2000.

Response Prepared and Submitted By:
R. Scott Mahoney
Vice President – Controller, Treasurer and Clerk

Attachment:

1. Field Operating Procedure Section 409 (as revised)

DRAFT B
FIELD OPERATING PROCEDURE
SECTION 409
Distribution Line Inspection Program

Distribution Line Inspection Program

Process

Annually, 10% of the distribution circuits within each region will be inspected with a goal of inspecting each circuit within a 10-year cycle. Inspections and other distribution operations will be conducted to maintain CMP's plan and system in such condition as will enable CMP to furnish safe, adequate and as far as practicable continuous service. Compliance as specified by the NESC. The inspection will consist of the following:

Safety

- All new construction, reconstruction, maintenance, and operation of CMP's distribution system.
- Unsafe conditions caused by erosion or heaving by frost.
- Any unauthorized use of poles or structure that could be unsafe or will interfere with the integrity of the system.
- Special attention to clearances with respect to buildings, bridges or structures, over or under traveled ways, water crossings and boat launch areas or any clearances to protect the public and/or equipment operators from contact.
- Locks on fences, padmount transformers, switches and enclosures.
- Infringement on CMP's neutral space.

Plant Condition

- Critically deteriorated plant caused by rot or breakage.
- Significant cracks in wood arms or poles.
- Broken insulators or hardware.
- Broken strands in conductors.
- Broken or loose tie wire.
- Evidence of oil leaks from transformers and equipment.

The field employee will complete the inspection form and forward to the appropriate department for evaluation and prioritization. The needed maintenance will be coordinated and prioritized. Any hazardous condition, that in the judgment of the field employee requires immediate action, shall be called in to the appropriate Service Center for repair/replacement.

Documentation

The *circuit inspection form information* will be entered into the distribution line inspection database. The inspection information entered will include the date of inspection and inspectors name, along with the inspection results.

EXHIBIT 9
TO CMP COMMENTS ON COMMISSION DRAFT REPORT TO LEGISLATURE

2005 System Improvement Projects with Circuits Operating at 90% or Greater of Rated Ampacity

Substation:	Circuit No.:	Phase:	Conductor Size/Type:	Amp. Rating:	Measured Amps:	% Overload:	Proposed Remediation:	2005 Plan?:
Oxford	437D1	Three	336 Al	240	269	112	Betterment 5416-2005 Add 2nd Circuit	Yes
Denmark	413D1	Single	#6 Copper	65	91	140	Betterment 5422-2005 Reconductor Berry Road	Yes
Lovell	430D1	Three	#6 Copper	65	66	102	Betterment 5418-2005 Reconductor Fryeburg State Road	No; loading (102%) does not require alterations at this point
Norway	435D2	Single	#6 Copper	65	62	95	Betterment 5415-2005 Reconductor Noble Road	No; loading (95%) does not require alterations at this point
Fryeburg	415D1	Three	336 Al	240	317	132	Betterment 5419-2005 New 12 kV Source Fryeburg	Yes
Deer Rips	412D4	Three	336 Al	240	300	125	Betterment 5161-2005 Extend 34 kV to Relieve Load	2006
Washington St	204D6	Single	#6 Copper	65	62	95	Betterment 1458-2005 Add Phase Small Point Road	Yes
Cooks Corner	217D3	Single	#6 Copper	65	60	92	Betterment 1460-2005 Add Phase Cundy's Harbor Rd.	Yes
Brooks	805D1	Three	#2 Copper	114	144	126	Betterment 3101-2003 Reconductor West Main St.	Yes
Ogunquit	640D2	Single	#4 Al	65	70	108	Betterment 4680-2005 Reconductor and Add Phase	No; loading (108%) does not require alterations at this point
Branch Brook	681D1	Three	336 Al	240	263	109	Betterment 4678-2004 Add New Circuit	Yes
Hiram	419D1	Three	336 Al	240	303	126	Betterment 4658-2004 Voltage Upgrade to 34 kV	Yes
Pratt Whitney	661D2	Three	336 Al	240	334	139	Betterment 4678-2004 Add New Circuit	Yes
Lambert Street	631D2	Three	336 Al	240	245	102	Betterment 4125-2004 Add New Circuit	Yes
Sewall Street	659D4	Three	336 Al	240	276	115	Betterment 4137-2003 Add New Circuit	Yes
Union Street	645D3	Three	336 Al	240	254	106	Betterment 4137-2003 Circuit to be Sectionalized	Yes
Bonney Eagle	610D2	Three	336 Al	240	350	146	Betterment 4109-2000 Add Padmount Stepper to Relieve Load	See Note below

EXHIBIT 9
TO CMP COMMENTS ON COMMISSION DRAFT REPORT TO LEGISLATURE

2005 System Improvement Projects with Circuits Operating at 90% or Greater of Rated Ampacity

Bonney Eagle	610D2-8	Three	1/0 AAAC	123	203	165	Betterment 4109-2000 Add Padmount Stepper to Relieve Load	See Note below
Prides Corner	647D1	Three	336 Al	240	362	151	Betterment 4125-2001 Add 3rd Circuit	This project was begun in 2004 and completed in 2005
Shaw Mills	660D1	Three	336 Al	240	302	126	Betterment 4109-2000 Add Padmount Stepper to Relieve Load	Yes
Swett Road	682D1	Three	336 Al	240	370	154	Betterment 4118-2001 Add 2nd Circuit Position	Yes
Winslow	861D9	Three	#4 Copper	86	85	99	Betterment 2151-2005 Reconductor to 336 Al	Yes
Manchester	233D2	Three	#4 Copper	86	86	100	Betterment 1172-2005 Add Phase and Balance	Yes

<u>NOTE:</u> ***These two conditions (Bonney Eagle) will be relieved when the Shaw Mill step down is installed. This was a 2005 project, but at the time of submission of this info, CMP had difficulty obtaining land for the transformer. CMP now owns the land and this project will begin Q4 of 2005, or Q1 of 2006.***

FEDERAL ENERGY REGULATORY COMMISSION
**1 Commission Opinions, Orders and Notices

Before Commissioners: Pat Wood, III, Chairman; Nora Mead Brownell, Joseph T. Kelliher, and Suedeen G. Kelly.

Policy Statement on Matters Related to Bulk Power System Reliability

Docket No. PL04-5-000

POLICY STATEMENT ON MATTERS RELATED TO BULK POWER SYSTEM RELIABILITY

(Issued April 19, 2004)

***61165** 1. This Policy Statement responds to recommendations in the U.S.- Canada Power System Outage Task Force's (Task Force) Interim and Final Blackout Reports on initiatives the Commission should undertake. This Policy Statement also responds to comments submitted after the Commission's December 1, 2003 public conference, in Docket No. RM04-2-000, on actions the Commission should take to promote reliable transmission service in interstate commerce (December 1 Reliability Conference). As such, the Policy Statement addresses a number of issues that relate to the Commission's role and policies regarding reliability of the nation's interstate bulk power systems. In particular, the Policy Statement clarifies Commission policy with regard to: the need to expeditiously modify existing bulk power system reliability standards, [FN1] to translate them into clear and enforceable requirements; public utility compliance with industry reliability standards and possible Commission action to address specific bulk power system reliability issues; cost recovery of prudent bulk power system reliability expenditures; the need for communication and cooperation between the Commission and the States; the need for communication and cooperation among the Commission, Canada and Mexico regarding reliability issues; consideration of reliability in Commission decision-making; and limitations on liability. This Policy Statement benefits citizens by providing clarity about this agency's policies to support and take what steps it can under current law to enhance transmission grid reliability.

2. The Commission strongly supports legislative reform to provide a clear Federal framework for developing and enforcing mandatory reliability rules. In the interim, the Commission is issuing this Policy Statement and taking other steps within its existing authority to promote greater reliability of the United States' bulk power system and its operation and to support industry efforts to improve the current voluntary industry based approach. [FN2]

Background

3. On August 14, 2003, an electric power blackout affected large portions of the Northeast and Midwest United States and Ontario, Canada. The blackout lasted up to two days in some areas of the United States and longer in some areas of Canada. It affected an area with an estimated 50 million people and 61,800 megawatts of electric load.

4. On August 15, 2003, President George W. Bush and Prime Minister Jean Chr€ tien established a joint U.S.-Canada Power System Outage Task Force (Task Force) to investigate the causes of the blackout and how to reduce the possibility of future outages.

**2 5. During the December 1 Reliability Conference, the Commission conducted a public inquiry into electric reliability. The conference addressed topics related to ensuring the reliability of the nation's bulk power system, including what the Commission should do to promote a reliable bulk power system (Docket No. RM04-2-000). Written comments submitted by John Derrick, Chairman PEPCO Holdings, Inc., on behalf of the Edison Electric Institute (EEI) proposed that the Commission continue to pursue its pending pricing policy for developing transmission infrastructure incentives and build on the NERC structure that is already in place by engaging the industry in a *61166 focused, sustained dialogue on (1) enforcing reliability standards and practices, (2) the six near-term critical reliability elements identified by NERC in an October 15, 2003 inquiry directed to control area operators and reliability coordinators, [FN3] (3) third-party liability issues, and (4) clarification of the relationship between grid operations, and market and business practices.

6. On April 5, 2004, the Task Force issued a Final Blackout Report, [FN4] replacing the interim report issued in November 2003. [FN5] The Final Blackout Report describes the blackout investigation findings and identifies the causes of the blackout. There are four groups of causes that coincided on August 14, 2003 to produce the blackout:

- inadequate system understanding;
- inadequate situational awareness;
- inadequate tree trimming; and
- inadequate reliability coordinator diagnostic support.

Further, the Final Blackout Report indicates that several entities violated NERC operating policies and planning standards, and those violations directly contributed to the start of the blackout. However, the Final Blackout Report finds that due to a variety of institutional issues, the NERC standards are sufficiently unclear, ambiguous and non-specific that it was possible for bulk power system participants to interpret these standards in widely varying ways that, while producing low reliability, could still be considered to comply with the standards.

7. The Final Blackout Report stated that the August 14, 2003 blackout was preventable and provided 46 recommendations to enhance grid reliability, which emphasize comprehensiveness, monitoring, training and enforcement of reliability standards. [FN6] Several of these recommendations suggest actions the Commission should take to improve bulk power system reliability. For example, the report recommends that the Commission not approve the operation of a new Regional Transmission Organization (RTO) or Independent System Operator (ISO) until the applicant has met the minimum functional requirements of reliability coordinators. [FN7] In addition, the Final Blackout Report states that the Commission should develop a Commission-approved mechanism for funding NERC and the regional reliability councils to ensure their independence from the parties they oversee, [FN8] clarify that prudent expenditures and investments for bulk system reliability will be recoverable through transmission rates, [FN9] and integrate a reliability impact consideration into our regulatory decision-making process. [FN10] The report

also states that operators who initiate load shedding pursuant to approved guidelines should be shielded from liability or retaliation. [FN11]

****3** 8. The Interim Blackout Report indicated (and the Final Blackout Report confirms) that, in the period of time immediately preceding the August 14 blackout, Northeast Ohio had significant reactive power needs. FirstEnergy, a Midwest utility identified as one of the entities whose violations of NERC standards contributed to the blackout, was severely deficient in reactive power to support the Cleveland-Akron area before the blackout. Based on these circumstances, the Commission determined that the availability of reactive power, and more generally, the availability of sufficient generation and transmission facilities in Eastern Ohio are matters deserving more study. [FN12] The Commission directed FirstEnergy to retain an independent expert to prepare a study of the adequacy of transmission and generation facilities in Northeastern Ohio. [FN13] FirstEnergy has retained an independent expert as directed and is currently preparing the required study, which will be completed in April, 2004.

9. Responding to the blackout and the blackout investigation, on February 10, 2004, the NERC Board of Trustees approved recommendations to take steps to improve the reliability of the bulk electric system, including a recommendation to review the reliability readiness of reliability coordinators and the major control areas. [FN14] NERC plans to complete the 20 highest priority reviews by June 30, 2004, inspecting the operators which serve over 80 percent of North America's electric load.

***61167** 10. The Commission supports NERC's and the industry's efforts to take concrete steps to improve system reliability. Pursuant to an explicit provision in its 2004 appropriation, the Commission is establishing a new reliability division to be staffed with grid-reliability engineering experts in the Office of Markets, Tariffs and Rates, to assure sound integration of reliability and market considerations in Commission decision-making. Members of this division are participating with other industry volunteers in NERC's reliability readiness reviews and supporting the development of new reliability standards.

11. The Congress is currently considering energy legislation, which would address the reliability of the nation's bulk power system based on mandatory industry compliance with enforceable reliability standards. The Commission strongly supports the enactment of legislation containing such a reliability provision. This Policy Statement is intended to be consistent with both current FERC authority and responsibility, and the implementation of such legislation.

Discussion

A. Need for Expeditious Revision of NERC Reliability Standards

12. Over the past 30 years NERC has developed "operating policies and planning standards" with which its members are expected to voluntarily comply. As mentioned above, the operating policies consist of a collection of standards, requirements and guidelines that, together, instruct on the reliable operation of interconnected systems operations and, as currently drafted, place the primary responsibility for reliable operations on control area operators. NERC's planning standards are intended to state the fundamental requirements for planning reliable interconnected bulk electric systems.

****4** 13. In 2002, NERC began developing clear and enforceable "reliability standards," under an American National Standards Institute (ANSI)-accredited process, which includes a voting model that provides for open participation and voting by industry stakeholders, weighted by industry segment. These new standards will be clear and unambiguous as to what needs to be done and who needs to do it to achieve reliable grid operations, and will include compliance measures for each standard. NERC is also working to transition its policies away from control area-oriented terminology suited for traditional vertically-integrated utilities and toward the terminology of a functional model that focuses on tasks or functions required for maintaining electric system reliability. The functional model recognizes changes to new industry structures that have emerged from the advent of open access transmission service. [FN15]

14. The Commission agrees with the critical need to replace the current standards with standards that are clear, unambiguous, measurable and enforceable. To date NERC has completed development of one interim reliability standard, relating to cyber security. NERC has identified approximately twelve additional reliability standards that it plans to develop that, when completed, will replace the existing operating policies and planning standards. NERC and the industry have recently agreed to expedite the development of these new standards and are currently working toward the completion and adoption of new standards by the end of 2004. The Commission supports NERC's commitment and our expectation is that such standards will be enforceable in early 2005. [FN16]

15. The Final Blackout Report identifies topics that are not currently addressed by NERC standards or are addressed so vaguely as to be ineffective, but are important in maintaining system reliability. Such "gaps" include vegetation management for transmission rights-of-way, line ratings, operator training, adequacy of operator tools, and minimum functional requirements and capabilities for reliability authorities and balancing authorities. [FN17] The Commission advises NERC and the industry to include these priority matters in the list of topics for which immediate reliability standards must be developed, and to develop such standards as quickly as reasoned deliberation allows.

16. The Commission requests status reports from NERC and the industry on the development of these revised standards. Pursuant to a recommendation in the Final Blackout Report, the Commission is working with the United States and Canadian governments to hold a meeting with NERC and the electric industry about how the ***61168** findings of the blackout investigation should affect electric reliability standards and regulation, and looks forward to discussing these issues in that meeting.

17. The Commission believes that NERC's reliability standards should represent a floor for grid operator and bulk system participants' reliability efforts, and not a ceiling. Utilities and other entities involved in transmission system reliability should strive toward achieving reliable transmission service and not simply act with the aim of meeting the minimum requirements that have been set forth in manuals and standards.

**5 18. The Commission recognizes that entities may be subject to regional reliability standards developed by NERC's regional reliability councils or State agencies. The Commission supports variations where the transmission provider or other relevant entity can demonstrate that regional reliability standards are necessary to account for physical differences in the bulk power system and are no less stringent than, and not inconsistent with, NERC's reliability standards. [FN18] Regional or State standards that do not account for physical differences and do not produce the same or a higher level of performance are not acceptable. Likewise, we cannot support regional or State reliability standards that result in variations that are less stringent and produce lower reliability than NERC standards. The Commission is concerned, however, that regional variations may create market seams or allow anti-competitive behavior and will watch carefully for any such problems.

19. In summary, we support NERC and industry efforts to translate the existing reliability standards into clear and enforceable standards by early 2005, and we encourage NERC to address the "gaps" in existing reliability standards.

B. Good Utility Practice

20. Nearly all transmission-providing public utilities are members of one of NERC's ten regional reliability councils. [FN19] NERC has taken the position that all members must voluntarily agree to operate their transmission systems consistent with NERC reliability standards.

21. In Order No. 888, the Commission required that all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce have on file an open access, non-discriminatory transmission tariff (OATT). [FN20] The pro forma OATT, issued as part of Order No. 888, contains numerous provisions that reference "Good Utility Practice," [FN21] some of which specifically relate to the reliable operation of the transmission grid. For example, "Control Area" is defined as a system or systems to which a common automatic generation control scheme is applied in order to, among other things, "maintain scheduled interchange with other control areas, within the limits of Good Utility Practice" and "maintain the frequency of the electric power systems within reasonable limits in accordance with 'Good Utility Practice."' [FN22]

22. With regard to network integration transmission service, the OATT provides that a transmission provider is responsible to plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice [FN23] and may curtail service consistent with Good Utility Practice to maintain system reliability. [FN24] Further, the OATT specifically requires that a network customer satisfy its control area requirements by either operating as a control area under NERC and regional reliability council guidelines, contracting with the Transmission Provider or contracting with another entity "consistent with Good Utility Practice, which satisfies NERC and the [applicable regional reliability council] requirements." [FN25]

****6** 23. In this Policy Statement, we clarify that the Commission interprets the term "Good Utility Practice" to include compliance with NERC reliability standards or more stringent regional reliability council standards. Accordingly, public utilities ***61169** that own, control or operate Commission-jurisdictional transmission systems should operate their systems in accordance with Good Utility Practice as set forth in the Commission's pro forma open OATT, including complying with NERC reliability standards.

24. With respect to ISOs and RTOs, they must comply with NERC reliability standards pursuant to both Order No. 888 and Order No. 2000. Order No. 888-A, in discussing the characteristics and functions of ISOs, states that ISOs should comply with "applicable standards set by NERC and the regional reliability council." [FN26] Likewise, with regard to RTOs, the Commission discussed in Order No. 2000 a specific requirement that RTOs follow NERC standards. The Commission determined that RTOs must have exclusive authority for maintaining the short-term reliability of the grid that it operates. In that context, the Commission concluded that:

the RTO must perform its functions consistent with established NERC (or its successor) reliability standards, and notify the Commission immediately if implementation of these or any other externally established reliability standards will prevent it from meeting its obligation to provide reliable, non-discriminatory transmission service.[[FN27]]

Accordingly, the Commission expects ISOs and RTOs to perform their functions consistent with NERC reliability standards (or with regional variations that are no less stringent than, and not inconsistent with, NERC standards) and the findings and recommendations of NERC audits.

25. In sum, the Commission expects public utilities to comply with NERC reliability standards and to remedy any deficiencies identified in NERC compliance audit reports and recommendations. The Commission will consider taking utility-specific action on a case-by-case basis to address significant reliability problems or compliance with Good Utility Practices, consistent with its authority. A failure to comply with such industry standards could in some circumstances affect Commission determinations as to whether rates are just and reasonable. For example, it may be appropriate to deny full cost recovery in circumstances where a transmission provider fails to provide full reliability of service. [FN28]

26. Generators, transmission customers and other market participants are also expected to support transmission system reliability, and to obey the directives of a balancing authority or reliability authority for operational reliability in real time. The Commission plans to explore this topic further to determine the best means to ensure that all market participants are held responsible to act to support transmission system reliability.

C. Cost Recovery of Prudent Reliability Expenditures

**7 27. The Commission understands that public utilities may need to expend significant amounts of money to implement measures necessary to maintain bulk electric system reliability, including vegetation management, improved grid monitoring and management tools, and improved operator training. The Commission is also aware that there may be uncertainty about public utilities' ability to recover as additional expenses the expenses necessary to ensure bulk electric system reliability, especially if they are operating under frozen or indexed rates. Further, the blackout investigation Final Blackout Report Recommendation 4 recommends that regulators clarify that prudent expenditures and investments to maintain or improve bulk power system reliability will be recoverable through rates. [FN29] Accordingly, the Commission assures public utilities that we will approve applications to recover prudently incurred costs necessary to ensure bulk electric system reliability, including prudent expenditures for vegetation management, improved grid management and monitoring equipment, operator training, and compliance with NERC reliability standards and Good Utility Practices.

28. In a Statement of Policy issued September 14, 2001, the Commission provided assurances to regulated entities that the Commission "will approve applications to recover prudently incurred costs necessary to further safeguard the reliability and security of our energy supply infrastructure in response to the heightened state of alert. Companies may propose a separate rate recovery mechanism, such as a surcharge to currently existing rates or some other cost recovery method." [FN30] The Commission stands by this policy and clarifies that the policy extends to the recovery of prudent reliability expenditures, including those for vegetation management, improved grid management and monitoring equipment, operator training

and compliance with NERC standards.

***61170** D. Commission Relationship with States on Reliability Issues

29. The Commission recognizes that many aspects of system reliability are within the purview of the states. To maintain and enhance reliability, it is necessary that all those with responsibility for the bulk electric system work together to achieve the common goal of a reliable electric system. Accordingly, the Commission intends to work closely with the states to address vegetation management, jurisdictional overlap issues regarding reliability upgrades, cost recovery, and other reliability-related issues of mutual concern. To date we have been holding such discussions with individual State officials, through the National Association of Regulatory Utility Commissioners, and through interactions on the joint U.S.-Canada Power System Outage System Task Force. We look forward to continuing and strengthening these efforts.

30. With regard to reliability "upgrades," we note that several State and regional entities have asked the Commission to recognize that State or regional reliability rules may be more stringent than those developed by NERC. For example, in follow-up comments to the Commission's December 1 Reliability Conference, the New York State Reliability Council, Northeast Power Coordinating Council and the Western Electricity Coordinating Council all indicated that, while they support efforts to develop enforceable, industry-wide reliability standards, such standards "should represent a floor rather than a ceiling." They stated that it is essential for regional entities to have the ability to promulgate more specific and more stringent regional and local reliability standards. According to these comments, more stringent regional criteria that address unique regional needs or concerns make for a more robust overall bulk electric system and allow greater flexibility when extraordinary events occur.

****8** 31. As discussed above, the Commission supports regional standards that are necessary to account for physical differences in the bulk power system and are no less stringent than, and not inconsistent with, NERC's reliability standards. The Commission recognizes that regional criteria may be necessary and that the State and regional entities have legitimate interests in enhancing reliability beyond the level achieved by compliance with NERC standards.

32. We are also interested in working together with the States and NERC to address and remedy any deficiencies in public utility implementation of reliability requirements, or any shortfalls in actual bulk system reliability.

E. Commission Relationship with Canada and Mexico on Reliability Issues

33. The Commission recognizes the common interest of the United States, Canada and Mexico in maintaining a safe and reliable interconnected North American bulk electric system. [FN31] In this vein, the Commission will work closely and cooperatively with officials designated by the Canadian and Mexican governments to achieve this common interest.

34. Further, the Commission will work closely with Canada to achieve common reliability of the interconnected transmission grid to attain consistent cross-border treatment of reliability standards and regulation as they affect bulk system participants and NERC under current regulatory conditions. When energy legislation is enacted, we will work closely with appropriate Canadian authorities to assure the success of the Electricity Reliability Organization (ERO) and address any issues required to assure that our nations share a reliable electric grid.

F. Recommendations of Blackout Investigation Final Report

35. In addition to recommending that the Commission allow recovery of prudently incurred reliability-related costs, discussed in Section C, above, the April 5 Final Blackout Report recommends or discusses several other actions related to the Commission and its regulation of public utilities. Below we adopt new policies and announce new steps in response to the final report.

Reliability of ISOs and RTOs

36. The Final Blackout Report's Recommendation 6 [FN32] recommends that the Commission not authorize a new RTO or ISO to become operational until the applicant has met the minimum functional requirements for reliability coordinators. In response to this recommendation, the Commission will continue its policy of taking reliability considerations into account before authorizing a new ISO or RTO to become operational. An ISO or RTO must meet all minimum functional requirements for reliability coordinators in order to fulfill its responsibility as reliability coordinator for the area within its footprint.

Consideration of Reliability Impacts in Commission Decision-making Process

37. The Final Blackout Report's Recommendation 9 [FN33] recommends that the Commission integrate a formal reliability impact consideration into our regulatory decision-making to ensure Commission actions improve, or at a minimum do not harm, reliability. In response to this recommendation, the Commission will continue its policy of ***61171** considering the reliability implications of Commission decisions, as appropriate.

Funding of NERC

****9** 38. The Final Blackout Report's Recommendation 2 [FN34] recommends that the U.S. and Canadian regulatory authorities develop a regulator-approved mechanism for funding NERC and the regional reliability councils, to ensure their independence from, the parties they oversee. In response, the Commission will appoint a staff task force to report to the Commission on potential mechanisms for funding NERC, the regional reliability councils, and, should energy legislation be passed, the Electricity Reliability Organization, to ensure independence from the utilities they oversee. This staff task force will be directed to work closely with our Canadian counterparts, as well as State regulatory authorities, NERC, the regional reliability councils, and industry participants, to develop funding options and recommendations. Such options should take into account funding mechanisms for current entities, such as NERC and the regional reliability councils, and entities created by the passage of reliability legislation.

Memorandum of Understanding with NERC

39. The Final Blackout Report recommends that government agencies in the U.S. and Canada decide whether to develop individual memoranda of understanding (MOUs) with NERC that would define the agency's working relationship with NERC, government oversight of NERC activities, if appropriate, and the reliability responsibilities of the signatories. [FN35] In response to this recommendation, the Commission directs staff to draft a MOU which will define NERC's working relationship with the Commission. In addition, this MOU will clarify the appropriate Commission oversight of NERC and the respective reliability responsibilities of both NERC and the Commission. This MOU will be signed by the Chairman, on behalf of the Commission.

G. Limitations on Liability

40. In view of the Commission's interpretation in this Policy Statement that Good Utility Practice includes compliance with NERC reliability standards and NERC compliance audit recommendations, the Commission will consider, on a case-by-case basis, proposals by public utilities to amend their OATTs to include limitations on liability. While this issue has not been resolved on a standardized basis, the Commission has entertained RTO transmission providers' specific proposals to amend their OATTs to include provisions addressing limitations on liability. [FN36] Such proposals should address the standard for liability (e.g., gross negligence and willful misconduct) and the types of damages for which the public utility may be liable (e.g., direct damages and not consequential or indirect damages).

By the Commission.

(SEAL)

Magalie R. Salas

Secretary

FN1. Current industry reliability standards are found in the North American Electricity Reliability Council's (NERC) Planning Standards and the NERC Operating Manual, with operating standards set forth in operating policies contained in the Operating Manual and Appendices. The operating policies include "standards" and "requirements," along with "guidelines" and "criteria." For purposes of this Policy Statement, the term "reliability standards" refers to the entirety of reliability-related policies now in the NERC Operating Manual and Planning Standards and those evolving through the formal standards development process.

FN2. Concurrent with the issuance of this order, the Commission is issuing an order directing transmission providers to report on their vegetation management practices related to certain overhead interstate transmission lines. Order Requiring Reporting on Vegetation Management Practices Related to Designated Transmission Facilities, 107 FERC ¶ 61, 053(2004).

FN3. NERC's six critical reliability elements include: (1) ensuring that high voltage transmission line rights-of-way are free of vegetation and other obstacles; (2) ensuring sufficient reactive power for voltage support; (3) strengthening where needed the reliability communications protocols between control area operators and reliability coordinators; (4) establishing as necessary more formal means to immediately notify control room personnel about failures of system monitoring and control functions; (5) ensuring that emergency actions plans and procedures are in place; and (6) ensuring that all operating staff are trained and certified in emergency drills.

FN4. U.S.-Canada Power System Outage Task Force, Final Report on the August 14th Blackout in the United States and Canada: Causes and Recommendations (April 2004) (Final Blackout Report). The Final Blackout Report is available on the Internet at http://www.ferc.gov/cust-protect/moi/blackout.asp.

FN5. U.S.-Canada Power System Outage Task Force, Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003) (Interim Blackout Report). The Interim Blackout Report is available on the Internet at http://www.ferc.gov/cust-protect/moi/blackout.asp.

FN6. Final Blackout Report at 139.

FN7. Recommendation 6. Id. at 147.

FN8. Recommendation 2. Id. at 143.

FN9. Recommendation 4. Id. at 146.

FN10. Recommendation 9. Id. at 147.

FN11. Recommendation 8. Id.

FN12. FirstEnergy Corporation, 105 FERC ¶ 61,372 (2003).

FN13. Id.

FN14. See Recommendation 3a. The text of the February 10, 2004 document is available on NERC's website, www.nerc.com.

FN15. Historically, control areas were established by vertically-integrated utilities to balance the control area's load with its generation, implemented interchange schedules with other control areas, and ensured transmission reliability. Industry restructuring in some areas has led NERC to restate its reliability standards in terms that fit the new - as well as the traditional - industry structures. This means replacing the term "Control Area Operator" with new terms that identify more closely which entity in a more disaggregated industry structure is responsible for complying with each NERC standard. To facilitate the update of its reliability standards, NERC has established the functional model. This model now recognizes a "Balancing Authority Area" as the collection of generation, transmission, and loads within the metered boundaries where a "Balancing Authority" maintains a load-resource balance. A "Reliability Authority Area" is recognized as having borders that may coincide with one or more balancing authority areas. A "Reliability Authority" may direct the "Transmission Operators" or Balancing Authorities to take action, for example, to maintain interconnection reliability operating limits. Also, as the functional model was being developed, the term "Reliability Coordinator" was used on an interim basis before Reliability Authority became the accepted term.

FN16. In this vein, the Commission notes NERC's April 5, 2004 announcements of the adoption of (1) Revised Compliance Templates and (2) Interim Guidelines for Reporting and Disclosure of reliability audit results and reliability standards compliance violations.

FN17. See Final Blackout Report at 21-22.

FN18. NERC recently explained that "regional standards may be more stringent than, but may not be inconsistent with or less stringent than, the NERC standards. Both sets of rules apply, and operators must comply with the more stringent one." March 12, 2004 Response to Questions posed by the Senate Committee on Energy and Natural Resources, Michehl Gent, President and CEO of NERC.

FN19. NERC's members are the ten regional reliability councils.

FN20. Order No. 888, Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded

Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 Fed. Reg. 21,540 (1996), FERC Stats. & Regs. ¶ 31,036 (1996), order on reh'g, Order No. 888-A, 62 Fed. Reg. 12,274 (1997), FERC Stats. & Regs. ¶ 31,048 (1997), order on reh'g, Order No. 888-B, 62 Fed. Reg. 64,688, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998), aff'd in relevant part sub nom. Transmission Access Policy Study Group, et al. v. FERC, 225 F.3d 667 (D.C. Cir. 2000), aff'd sub nom. New York v. FERC, 535 U.S. 1 (2002).

FN21. Order No. 888 defined "Good Utility Practice" in section 1.14 of the pro forma OATT as follows: Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region. (Emphasis added)

FN22. Pro forma OATT at section 1.6.

FN23. Id. at section 28.2.

FN24. Id. at section 33.7.

FN25. Id. at section 35.2.

FN26. Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,247-48.

FN27. Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809 (2000), FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,089 at 31,106 (1999), order on reh'g, Order No. 2000-A, 65 Fed. Reg. 12,088 (2000), FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,092 (2000), aff'd, Public Utility District No. 1 of Snohomish County, Washington v. FERC, 272 F.3d 607 (D.C. Cir. 2001).

FN28. See, e.g., Village of Freeport, New York v. Consolidated Edison Co. of New York, Inc., 87 FERC ¶ 61,301 (1999) (setting for hearing whether ConEd followed good utility practice in providing firm transmission service required by the OATT and, if not, what remedies are appropriate); Green Mountain Power Co., 59 FERC ¶ 61,213 at 61,739 (1992).

FN29. Final Blackout Report at 146.

FN30. Extraordinary Expenditures Necessary to Safeguard National Energy Supplies, 96 FERC ¶ 61,299 at 61,129 (2001).

FN31. The northern portion of Baja California Norte, Mexico is interconnected with the western United States and Canada and is part of the WECC, a NERC region.

FN32. Final Blackout Report at 147.

FN33. Final Blackout Report at 147.

FN34. Id. at 143.

FN35. Id.

FN36. See Wholesale Market Power Platform White Paper (April 28, 2003) (stating that a standard tariff provision limiting liability for transmission providers would be included in the Final Rule Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design). See also Midwest Independent Transmission System Operator, Inc., 100 FERC ¶ 61,144 (2002) (conditionally accepting for filing a proposed OATT revision that would limit the liability of the Midwest ISO and Midwest ISO transmission owners for certain damages related to services provided under the Midwest ISO OATT); and ISO New England, et al., 106 FERC ¶ 61,280 (2004).

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